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CORRELATION OF LABORATORY DESIGN PROCEDURES WITH FIELD PERFORMANCE IN SURFACTANT-POLYMER FLOODING

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ABSTRACT

As an aid in assessment of laboratory procedures for optimizing surfactant and polymer flooding systems, a survey is presented of field tests whose performance has been well documented and analyzed. The reasons for failure to attain predicted recovery are summarized: reservoir heterogeneity, loss of injectivity and mobility control, incomplete determination of surfactant and polymer characteristics under changing conditions, neglect of ion-exchange effects and the presence of gypsum, unrealistic evaluation of surfactant retention, inaccurate residual oil values, and emulsification. Statistical analysis indicates that surfactant concentration and the size of surfactant and polymer slugs are the most important factors in oil recovery by surfactant-polymer flooding. Recommendations are made on how design procedures can be extended and improved, with an emphasis on laboratory programs.

INTRODUCTION

Before the abatement of chemical enhanced oil recovery (EOR) activities because of declining oil prices, a variety of field tests had been designed and implemented. For many of these tests, complete descriptions were published, including design considerations, laboratory development, field operations, and results. It seems timely to examine these results in a comprehensive manner and by comparing performances with expectations, to identify ways in which design and laboratory testing can be improved. When the petroleum economy improves so that chemical EOR can be actively resumed, this previous experience should provide tools for greater predictability and reduced risk.

The field tests that are discussed here have undergone extensive reappraisals. All of them have fallen short of the ideal forecasts based on evaluations during the design stage. However, only three (Lawry, Delaware-Childers, and El Dorado) were stark technical failures. The brief descriptions of individual projects presented are focused on the reasons that have been offered for their poor performance. Reservoir evaluation is of crucial importance, but this subject is not treated here. The laboratory-based factors are singled out for particular attention.

Quantitative details on recovery, slug composition and size, etc., are listed in table 2, but this review is not intended as a critique of EOR processes.

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SURVEY OF EVALUATIONS OF FIELD TESTS

Bradford, PA

A set of tests of the Maraflood™ process has been carried out by Pennzoil. After an encouraging pilot on the Bingham lease,[1] two expanded projects[2-3] were undertaken. The early tests showed a loss of injectivity due to plugging by the polymer slug, which tended to form gels. The most recent test[3] displayed injectivity declines also during surfactant injection, but they were remedied by HCl treatment. The vertical conformance was poor, with no detectable penetration of the low-permeability zones.

There was some trouble with emulsions when sulfonate and oil were produced together, and the operators suspected that emulsion formation affected flow within the reservoir. Producing wells along the northern boundary made the poorest showing, probably because invasion by external brine degraded the surfactant.

A separate test at the Lawry lease,[4] in a very tight region of the formation (permeability, 8 md; porosity, 13%), was a technical failure. The preflush and surfactant slug were redesigned, and polyacrylamide replaced polysaccharide in the mobility buffer. The failure of the test was largely associated with the tightness of the sand. Only a very low rate of injection was possible, even though injection pressure exceeded parting pressure. Stimulation was of little benefit. The sweep efficiency was abnormally low, estimated at 14%, even though the heterogeneity was only marginally larger than at the Bingham lease (Dykstra-Parsons coefficient of 0.88 compared with 0.84). Evidently heterogeneity has a more pronounced effect at low permeability.

The loss of sulfonate amounted to about 97%, which was attributed to retention by the oil, promoted by the formation of oil-soluble calcium sulfonate after ion exchange.

Salem, IL

A well-documented test of the "low-tension" (dilute-surfactant) process was designed by Mobil Oil and operated by Texaco. An early test of the Mobil process at Loma Novia, TX,[5] was unsuccessful because of inadequate mobility control. This was improved for the Salem test.[6-8] Still, the conformance was deficient. The flow pattern was distorted by a permeability gradient, as indicated by transmissibility tests, and by a pressure gradient indicated by tracer tests. Observation-well tests showed that the process was effective in mobilizing oil, but even making allowances for conformance, recovery was less than expected from laboratory work. Some evidence was cited that suggested insufficient reservoir conditioning (incomplete sweep by the preflush), not enough volume of surfactant, or a still-inadequate mobility control. The overall surfactant loss was similar to the amount predicted from laboratory measurements.

A follow-up test of the Mobil process was performed at West Burkburnett, TX,[9] with disappointing results. In an alkaline pretreatment, Na_2CO_3 and $Na_5P_3O_{10}$ were excessively consumed by divalent exchange ions, leaving two-thirds of the injected surfactant slug unprotected. The sweep efficiency was adversely affected by heterogeneous transmissibility, stratification, a pressure gradient, and extension of fractures by injection. Analysis of the produced fluids indicated degradation or retention of polymer, resulting in reduced mobility control.

Texaco subsequently applied a high-surfactant-concentration process at the Salem field with better results.[10-11] In the high-permeability zones, which were overinjected (0.30 to 0.45 PV of surfactant), recovery efficiency was greater than 70%, as in laboratory corefloods. But the recovery suffered because of heterogeneity and uneven pressure control external to the pattern. The surfactant composition was altered in situ by adsorption of the high-equivalent-weight portion, but this was a reversible effect. The polymer was severely degraded by bacterial contamination at the surface facilities. The resulting loss of mobility control substantially slowed the oil production.

Big Muddy, WY

Another "low-tension" flood was conducted by Conoco.[12-14] The principal problem in the project was that the pattern was not isolated: chemicals and mobilized oil moved out of the pattern, and external brines entered it. This was indicated by the response of rates and pressures to operational changes, by high chlorides in some producing wells, and by temperature surveys and falloff tests that indicated loss of chemical slug. The variation among production wells in time of appearance of chemicals was evidence for pattern imbalance and poor areal sweep. These effects are attributed to a natural fault-fracture system and to an injection pressure that exceeded the parting pressure.

Polymer viscosity is believed to have been excessive at the shear rate representative of the low injection rate.

A set of measurements was designed explicitly to demonstrate that the small barium content of the reservoir was not detrimental to performance.

Robinson, IL

Two large-scale projects, 219R (113 acres)[15] and M-1 (407 acres)[16-19] were designed by Marathon, after several smaller projects in the Robinson sand with improving design and increasing success. On a large scale, problems of confinement of flow within the pattern are minimized.

The 219R test experienced injectivity problems with both surfactant and polymer, which required fine tuning of composition and avoidance of oxidizing conditions that convert iron to the ferric state. In the M-1 test, an aggressive fracture stimulation program during polymer injection was necessary to maintain injection and withdrawal rates. Some channeling was induced, which augmented natural random channels (revealed by tracer tests). This required shutting in several producing wells to even out areal sweep. Vertical conformance was hampered in the usual sense by stratification of permeability. One layer gave reasonable values of permeability as measured in cores, but had very low transmissibility because of microheterogeneities due to mica. Diagnostic wells showed that oil banks were formed initially in low-permeability zones, but lost their integrity before reaching producing wells. Thus, production was primarily from high-permeability zones. It was also found that sulfonate penetrated some areas that were not reached by polymer. The reason for this is not known.

Abnormally severe emulsions were encountered at the peak of sulfonate production.

Bacterial strains developed that were resistant to a biocide, so it was necessary to increase concentrations and switch biocides from time to time.

The crude oil sulfonate slug (COSS) was somewhat less effective than more expensive products. It was salinity sensitive, which was a disadvantage in the area around new wells in the infill drilling program. Also, alcohol content had to strike a balance between excess viscosity and wax precipitation.

Delaware-Childers, OK

The Department of Energy aqueous surfactant pilot[20-21] in Delaware-Childers (OK) field produced virtually zero tertiary oil. Evaluation wells showed that while oil was not moved out of the reservoir, it was redistributed vertically from regions of high saturation to regions of low saturation. Chemical recovery showed a strong NE-SW directional permeability that was not evident in core analysis and was not clearly indicated by pressure interference tests. However, it was inferred that there was a major permeability barrier in the southeast quadrant of the 5-spot pattern.

Surfactant was strongly retained, primarily in the residual oil. This alteration to an oil-external microemulsion was found to be due to dilution and a changing water-oil ratio, not to salinity change.

There was an unexplained increase in mobility of the polymer slug under flow conditions in the reservoir. The polymer was not degraded during storage of solutions. The increase was shown not to be a hardness or salinity effect.

A somewhat saline polymer solution was used in the project because it was found that seasonal variations in the "fresh" supply water could cause a twofold variation in viscosity.

North Burbank, OK

Phillips designed and operated this aqueous-surfactant project.[22-23] The reservoir is oil-wet, and has natural east-west fractures. During polymer injection, pressure exceeded parting pressure because of declining injectivity. This augmented the natural fracture system in some cases; remedial gelled-polymer treatments were successful in some of these cases. However, several workover operations performed during chemical injection probably allowed polymer and surfactant to enter different parts of the reservoir. This effect was documented by a diagnostic well at one site where sulfonate was present, but no polymer was detected. (Shifting oil saturation can also alter flow patterns.) The surfactant retention exceeded that expected from laboratory measurements of adsorption, and was attributed to partitioning into the oil phase. The simultaneous partitioning of alcohol into the aqueous phase, due to changing salinity and hardness, degraded the effectiveness of the surfactant slug. The saline preflush (which followed a fresh-water slug) was insufficient to displace divalent ions from exchange positions on the reservoir rock.

In this project, injection rates in and around the pattern were painstakingly controlled to eliminate any pressure gradient across the pattern.

El Dorado, KS

Cities Service attempted to compare the effectiveness of an aqueous surfactant (Shell) with that of an oleic surfactant (Uniflood™) process in side-by-side tests.[24-25] Unfortunately, this was a very unfavorable reservoir for these tests. The presence of gypsum and exchangeable barium caused the aqueous surfactant to partition into the oil and be retained by phase trapping; and it totally consumed the alkaline preflush in the Uniflood process. In addition, there was a considerable amount of micro-stratification by micaceous laminae, which blocked many oil-bearing zones from penetration by injected fluids. Moreover, chemicals and mobilized oil were swept out of the pattern by a substantial east-west pressure gradient.

Injectivity problems were encountered because of polymer plugging in the Shell process and problems with both slugs in the Uniflood process. Fracture treatments caused channeling and premature breakthrough. All these factors, added to natural heterogeneity, led to low sweep efficiency. Acid stimulation of the wells used for the Uniflood process made an additional contribution to nullifying the alkaline preflush.

It was felt[25] that the project design suffered from not analyzing the performance or previous injection projects (air, steam, and water) and from a questionable geological analysis of the depositional environment of the formation. The deltaic model proposed by the operator is not compatible with the presence of gypsum, the microlaminae of mica, and the anomalously large amounts of barium and strontium, all of which contributed to the poor performance of the project. The more probable model is a migrating complex of tidal channels. If this had been recognized, adverse conditions would have been strongly indicated.

Bell Creek, MT

Gary Operating Co. conducted another test of the Uniflood™ process, first in a pilot[26-28] and then (as Gary-Williams) in an expanded project.[29] There were some differences of opinion in the evaluation of the pilot,[26-27] but it is generally agreed that reservoir heterogeneity was, more than usual, a major cause of unsatisfactory performance. Aside from directional and varying permeabilities and stratification, there was a pronounced permeability barrier in the southeast quadrant. The net thickness of the reservoir was only 6 feet.

Other factors included a sulfonate product that failed to meet specifications, having an excess of low-molecular-weight components. This was partly compensated by altered alcohol content, but the salinity (in hindsight) was kept too low. The residual oil was overestimated by the waterflood simulation and tracer methods used.

The expanded test[29] improved on all these deficiencies and performed much better.

Wilmington, CA

The City of Long Beach applied the Maraflood™ process to their reservoir that has a heavy (17° API) oil in unconsolidated sand.[30-31] The chief difficulties were operating problems, including corrosion caused by anaerobic bacteria. In the early stages, the downtime was 25%. A minor difficulty was quality control of the surfactant slug because of variations in the composition of the hydrocarbon constituents.

Both design and project evaluation were hampered by deficiencies in reservoir evaluation. There were major uncertainties about the oil saturation after waterflooding. The degree of transmissibility of a prominent fault was not determined definitively. Tracer tests were not handled adroitly.

The accuracy of prediction was considerably reduced by the lack of quantitative data on phase behavior and rheology.

A NW-SE pressure gradient probably contributed to reduced recovery efficiency.

Glennpool, OK

Gulf-Chevron conducted this test of the aqueous surfactant process. A pilot has been completed,[32-33] and an expansion (both in area and vertical coverage) is in progress.[34] The surfactant slug was adjusted to the boundary between Type II^- and Type III microemulsions to anticipate increases in salinity. The persistence of low interfacial tension and the mobilization of oil surpassed expectations at the observation wells, but the oil recovery at production wells was less than that predicted from laboratory work.

Chemicals were lost to non-pay zones outside the pattern and below the level of the target zone. This conclusion was based on pulse testing and the appearance of sulfonate outside the pattern. Also, very irregular sweep was indicated by uneven production of chloride and oil.

Polymer sampled at the observation well had very low viscosity. No explanation was offered. In a sense, the overproduction of sulfonate and oil at the observation well was as significant a discrepancy from laboratory results as was underproduction at producing wells.

No injectivity problems were encountered with either slug. However, there was some plugging of producers by precipitation of sulfonates in the presence of high concentrations of Ca, Ba, Fe, and Na; also by carbonate and sulfate scales and iron oxide (from corrosion).

Loudon, IL

Exxon conducted two dissimilar pilot tests in this field. The fairly unsuccessful first test[35] suffered because the conformance of the surfactant slug exceeded that of the preflush, so the surfactant was degraded on penetrating regions of high salinity.

The sodium carbonate preflush caused some scaling. There was an unexplained 75% loss of polymer.

In the second test,[36] the loss of polymer (polysaccharide) was the major problem and was clearly identified as due to bacterial action. There were two independent effects: loss of viscosity (depolymerization) and destruction of carbohydrate. Both reactions were fully arrested by formaldehyde, at least over the short time frame of transmittal through the 0.7-acre pattern.

The small pattern allowed for detailed reservoir description, avoiding undefined heterogeneity problems. No injectivity loss occurred, due to precautions taken to maintain a reducing and acid chemical environment.

A proprietary aqueous surfactant with high brine tolerance was used. Laboratory tests were run on rock samples cored to maintain native-state wettability. Surfactant retention was only about half that expected from laboratory tests.

Chateaurenard, France

This project by Elf Aquitaine consists of a completed pilot[37] and a continuing industrial test.[38] The surfactant slug is similar to that used in the Maraflood process. In the pilot, conformance and containment were problems, as usual. Because of heterogeneities and a pressure gradient, the sweep efficiency was only about 50%. Analysis showed that 82% of the fluids produced at one well came from outside the pattern, and that 37% of the injected chemicals were transported out of the pattern.

The unique feature of this project is the freshness of the formation water (less than 500 ppm TDS). This can be a disadvantage because low salinity tends to be associated with a high proportion of divalent cations in exchange positions. This promoted formation of oil-soluble sulfonate salts, so the surfactant was retained by phase trapping. Also, the salinity-gradient technique could not be used.

Nevertheless, oil recovery in the pilot was quite good, and the industrial scale test made only minor alterations in slug composition to minimize ion-exchange effects. A proposed Na_2CO_3 preflush to fix divalent ions showed considerable promise in laboratory tests.[39]

THE NEED FOR LABORATORY DATA

Table 1 gives a simplified summary of the identified reasons why these field tests of surfactant-polymer flooding fell short of predicted results. By far the most important cause is geological irregularities, which lead to low sweep efficiency and chemical loss. As mentioned, the recognized need[3,18] for improved reservoir description is outside the scope of this report. It should be mentioned that there are computational aids[40,41] for tailoring slug sizes to reservoirs of known heterogeneity, which utilize laboratory data as input. More importantly, some "heterogeneity" effects that are not geological can be combatted by chemical means, for example:

1. the use of surfactants and polymers less sensitive to expected changes in the chemical environment;

2. improved surfactant performance, so that oil mobilization creates a coherent bank rather than a redistribution of static saturation; and

3. a better match of mobility for all slugs -- preflush, surfactant, polymer -- so that they each sweep the same area.

The first two items are laboratory research goals that have been actively pursued. A chronological examination of field test results will confirm that progress has been made in improving performance.

However, there is a need for systematic laboratory data in designing a specific field test. This need is twofold: to identify potential problems, and to provide input data for simulation. One version of the University of Texas streamline micellar-polymer simulator[42] lists 61 parameters that require laboratory evaluation. As a practical matter, many will have to be estimated by non-experimental methods (e.g., analogy), or defaulted. The properties that are nearly always measured are permeability, porosity, temperature, brine composition, concentrations of recovery chemicals, oil saturation, and oil density and viscosity. Less commonly measured parameters are

- polymer characteristics under reservoir conditions,
- phase behavior,
- adsorption,

- ion exchange behavior,
- interfacial tension,
- relative permeability (reflects wettability),
- permeability reduction factor,
- capillary pressure - desaturation curves, and
- dispersion coefficients.

Most of these parameters are strong functions of chemical composition. The first four, along with oil saturation, are the ones that showed up as problems in the foregoing field-test diagnoses. Not related to simulation are the problems of emulsification and bacterial degradation. These are the areas for improvement in laboratory practices, either by improved techniques or by simply recognizing that it is important to collect more comprehensive data.

Oil Saturation

Problems in the determination of oil saturation in cores and reservoirs is the subject of a large volume of literature,[44] which will not be reviewed here.

Polymer Characteristics

Injectivity problems with the polymer slug have been attributed to a tendency to form gels under wellbore conditions. Realistic testing should be carried out under these conditions; or means should be planned in advance for proper control of the conditions. Although most of the field problems were with polymers, the oil-rich character of Maraflood and Uniflood slugs requires tailoring to avoid excess viscosity, the plugging effect of wax crystals,[15,25] and iron oxide formed when pH and Eh undergo adverse variations. Marathon concluded in the 219R test[15] that "Injectivity testing of both micellar slugs and polymer solutions is an important part of project design which should precede selection of a fluid system for a given reservoir."

The loss of mobility control has often been ascribed to shear or bacterial degradation. In some cases, the decreased effectiveness of mobility control has not been explained.[14,17,20,23] In view of the prevalence of mobility problems, a more aggressive testing program on polymers is indicated, including the influence of divalent and exotic (sulfide, borate) ions and requirements for control of pH and Eh in order to recommend steps for effective management of problems with degradation and gelling.

As overdesign is needed for good sweep efficiency,[40,43] it is desirable to have the rheological parameters of a polymer well mapped, so that simulation can lead to an economic optimization of slug size and concentration. It has been suggested that it might be optimal to dispense altogether with polymer and all its problems,[41,45,46] but this is not feasible with the present state of the art.

Adsorption

Although adsorption has commanded much attention, there is increasing recognition that phase trapping is often the dominant mechanism of surfactant retention. In any case, measurements will be more meaningful if made on reservoir minerals in their native state of wettability. In two tests, retention was at or below the laboratory value: the Salem I was a low-tension test not involving microemulsion,[6] and in Loudon II the cores were taken so as to preserve wettability.[36] Retention should also be measured with native-state brines. For example, loss of CO_2 content will raise pH and precipitate iron, each of which can affect adsorption and surfactant partitioning.

Phase Behavior

As phase behavior must include both salinity and concentration variations, the results are conveniently developed in the form of salinity requirement diagrams. The most important factors are the optimal conditions and the width of the three-phase (or low-interfacial-tension) region. In addition, knowledge of the distribution coefficient, together with the residual oil saturation (as a function of capillary number) can give surfactant retention. The techniques for phase behavior and interfacial tension measurements are well developed. Procedures for salinity, concentration, or temperature scans are straightforward. In some cases, there is ambiguity about whether laboratory-equilibrated samples are representative of dynamic conditions in a reservoir. Apparently the most serious omission in many cases has been the effect of divalent ions. Wang, Lake, and Pope[42] used a rule of thumb that calcium is equivalent to five sodiums. All alkaline earth ions are generally treated as equivalent. This assumption can be a source of error, considering the variations in solubility of carbonates, silicates, and hydroxides of the different ions. For example, barium was given separate consideration in the El Dorado[25] and Big Muddy[12] tests. It might be well to get some estimate also of the effects of iron and pH. In the El Dorado test, interaction of surfactant and polymer was suspected of having an adverse effect on phase behavior.

Ion Exchange Behavior

It has been noted that preflushes designed only to remove hard brines have left damaging amounts of divalent cations in exchange positions. Any reservoir containing significant amounts of clays, especially chlorite and smectite, should be evaluated for ion exchange capacity and how it is distributed among sodium, divalent, and acid sites. A determination of distribution coefficients and separation factors would improve our knowledge of quantitative behavior, but might be prohibitive in expense.

Emulsions and Bacteria

Many commercial treatments are routinely available to treat produced emulsions and bacterial problems. In some of the projects,[22,25] methods of handling problems were considered in advance. The fact that these effects were sometimes a serious handicap serves as a warning that they should not be overlooked. Bacteria can degrade chemicals, or cause plugging or corrosion. Corrosion was listed as a detriment only in the Wilmington test, but it may be a more widespread problem than published reports would indicate.

Other Factors

Some other measurements that did not enter into the simulation process can be significant in screening and design. Mineralogical studies will reveal the presence of gypsum, which was a serious problem in the El Dorado[25] test. Even 1% can be fatal, and this is at the limit of detectibility of X-ray diffraction. Microscopic methods must be used, or inferences drawn from brine analysis.

The unconsolidated nature of the Wilmington sand[31] required frequent workovers. Any means that can be designed to stabilize clays and other mineral components will be of value.

Oil acid number as one criterion for supplementing surfactants with alkaline chemicals is a straightforward measurement, but should not be considered definitive.[47]

Measurement of molar volume of the oil can serve as a guide to selection of a surfactant.[48]

RELATIVE IMPORTANCE OF THE VARIOUS FACTORS

A helpful means of giving a priority rating to design factors that need improving is a statistical analysis of the production response in field tests to the project parameters. Table 2 presents a re-tabulation of the data examined in previous surveys by Lake and Pope,[49] Holm,[50] and Lowry, Ferrell, and Dauben.[51] Some errors in the previous tabulations have been corrected; some of the data reinterpreted; and projects have been added that were completed more recently. A few projects previously considered are omitted because the data are notably incomplete.

The original studies made comparisons between recovery efficiency (RE) and the several parameters on an individual basis. A moderate level of confidence was found for correlations with capillary number, resident salinity (S), surfactant concentration (C_s), total amount of surfactant, polymer concentration, and size of the mobility buffer slug (V_p). In this study, the method of Mendenhall[52] was used to get a multidimensional regression analysis. This is intended to reduce the scatter in one variable caused by changes in the other variables. Polymer concentration was omitted because it was not considered representative of mobility control when salinity and polymer type differed widely among the projects. The injection rate (q) was used directly, since it is the most important determinant of the capillary number in the absence of data on interfacial tension. The importance of surfactant slug size (V_s), found to be unimportant in previous analyses, was reexamined; it replaced total surfactant. A previously neglected parameter, the alcohol/surfactant ratio (A), was added. The resulting model is

$$RE = a_0 + a_1q + a_2S + a_3C_s + a_4V_s + a_5A + a_6V_p \qquad (1)$$

The output from this analysis is

Coefficient	Value	Confidence level that $a_i \neq 0$, %	Relative magnitude of term
a_o	-16.7	84	17.0
a_1 (injection rate)	0.013	<50	0.1
a_2 (salinity)	0.48	71	2.0
a_3 (surfactant conc.)	2.58	97	15.0
a_4 (volume of surfactant)	0.84	98	11.0
a_5 (alcohol/surfactant)	8.42	86	4.0
a_6 (volume of polymer)	0.11	92	7.0

The relative magnitude is the product of the median value of a parameter and its coefficient. The surfactant concentration and the slug size are the most important parameters. Mobility buffer size was found to be less important than the surfactant parameter. This differs markedly from conclusions of the previous investigators. Part of the difference comes from omitting the early Robinson sand tests, for which data are insufficient to use the full model; and part comes from including the two El Dorado tests and the Bell Creek test, which deviate markedly from Lake and Pope's[49] single-parameter correlation.

The injection rate and the resident salinity seem to be of little importance (in fact, the sign of a_2 is counterintuitive). Some deficiencies of this type of analysis should be emphasized:

1. It is sometimes difficult to determine the active surfactant concentration from published reports.

2. Variable sweep efficiency strongly influences the numerical values of the input data. Some results, but not all, reported q and slug sizes for the invaded zone only. This is particularly important for a single, normal 5-spot pattern in which much of the injected fluid goes out of the pattern.

3. If the project results are not carefully analyzed, the reported RE may include oil mobilized by continued waterflooding and that due to reengineering the project.

4. The conclusions are sensitive to which data are input, as indicated by the effect of adding El Dorado and Bell Creek to the Lake and Pope data. The degree of scatter is shown in figure 1. The open points were not used in deriving the

statistical model but are calculated approximately from the incomplete data available.

5. The nonzero value of a_0 suggests that important factors have probably been omitted. Most notable are surfactant phase behavior, adsorption, and ion-exchange effects. These factors are omitted here because the paucity of data would have considerably reduced the number of projects included in the complete analysis. However, we can compare the single-parameter correlation coefficients derived by Lowry et al.[51] from the existing data:

salinity deviation	-0.39
adsorption	0.10
clay fraction	0.21

The salinity deviation (departure from design) is related to phase behavior and shows a fairly strong correlation in the expected direction. Clay fraction is a measure of exchange capacity and is weakly correlated in the unexpected direction. Adsorption is not a significant parameter in these published field data although a sensitivity test in simulation[40] indicates it should be important.

SUMMARY AND CONCLUSIONS

1. Reservoir heterogeneity is the most frequently cited reason why field performance of surfactant-polymer flooding is lower than predicted. This can be ameliorated to a limited extent by improved design of surfactant and polymer slugs.

2. Loss of injectivity and loss of mobility control have occurred because of a failure to evaluate polymer performance under the actual conditions in the wellbore and the reservoir. Injectivity testing should be performed with both the polymer and the surfactant.

3. Departure of the surfactant from optimal conditions is a significant factor in performance. It is caused by partitioning, dilution, and changing ionic environment. These effects should be anticipated in laboratory design.

4. Ion exchange effects are believed to have had an adverse effect in many projects. Unfortunately, this is not supported by the correlation between oil recovery and

clay content. Laboratory procedures need to give more attention to the quantity and species of exchangeable ions. Mineralogical analysis should identify the types of clay and also the possible presence of gypsum.

5. The surfactant concentration and the size of surfactant and polymer slugs are important factors in recovery. Since they also have a major impact on cost, extended mapping of phase behavior and rheological properties is needed for input to simulators, so that the cost-benefit ratio can be optimized.

6. Phase trapping is probably a more important cause of surfactant retention than adsorption. Both phenomena need to be appraised under reservoir conditions of brine composition and wettability.

7. An accurate determination of residual oil saturation is important for good simulation.

8. Strategies should be developed in advance for dealing with bacterial degradation and emulsion problems.

9. Improvements in the design and performance of surfactant oil-recovery field projects over the past 20 yeas are a testimony to the value of laboratory research.

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TABLE 1. - Reasons for performance defect

<u>A. Related to laboratory work</u>	
Surfactant slug degradation (ionic effects, adsorption, partitioning)	Lawry, Salem II, M-1, North Burbank, Delaware-Childers, Bell Creek, Chateaurenard
Inadequate data on surfactant	Lawry, Wilmington
Deficient preflush Burbank,	Salem I, West Burkburnett, North El Dorado (Chesney)
Mobility control: polymer loss/ degradation	Salem II, West Burkburnett, Delaware-Childers, El Dorado (Chesney), Glennpool, Loudon II
Mobility control: polymer bypassed surfactant	M-1, North Burbank
Injectivity (polymer)	Lawry, 219R, El Dorado (Chesney)
Excess viscosity	Big Muddy, M-1 (corrected)
Produced emulsions	Bingham, M-1
Mineralogy and ion exchange	Lawry, West Burkburnett, North Burbank, El Dorado, Chateaurenard
<u>B. Geological and Operating Problems</u>	
Heterogeneity	Lawry, Salem I, Salem II, West Burkburnett, Big Muddy, M-1, Delaware-Childers, El Dorado, Bell Creek I, Glennpool
Crossflow, brine invasion, loss outside pattern	Bingham, Salem I, Salem II, West Burkburnett, Big Muddy, El Dorado, Glennpool
Exceed parting pressure	Lawry, West Burk., Big Muddy, North Burbank, El Dorado (Hegberg)
Bacteria	Salem II, M-1, Wilmington, Loudon II
Many workovers	North Burbank, Wilmington
Scale in producers	Glennpool, Loudon I

TABLE 2. - Data on field tests of surfactant flooding

Test No.[1] LFD	LP	New	Ref	Brief name	Injection rate, bbl/ft/d	Reservoir salinity, % TDS	Surfactamt concentration, % active	Slug size, % PV invaded zone	Alcohol/surf. wt, ratio	Polymer slug, % PV	Recovery,[2] % WFRO
1			26-28	Bell Creek pilot	60.	0.74	8.0	3.5	0.13	100.	14.
2			29	Bell Creek expansion	14.	0.74	8.0	4.6	0.13	75.	28.
3	1			Benton pilot	2.0	11.	1.3	31.	0.	99.	24.
4	2		12	Big Muddy pilot	3.1	0.78	2.5	25.	1.4	30.	36.
5			13-14	Big Muddy demonstration	2.8	0.78	3.0	10.	1.4	20.	22.
6	3			Boregos	([3])	3.3	2.3	47.	0.	0.	20.
7	4		1	Bradford Bingham	4.6	0.30	13.	6.0	0.15	14.	39.
8	5		2, 3	Bradford Bingham expansion	3.6	0.30	12.	5.0	0.082	8.	37.
9			4	Bradford Lawry	0.8	0.30	9.0	9.4	0.0	41.	5.3
	6			Bridgeport	([3])	([3])	9.0	8.5	1.6	87.	48.
		A	37	Chateaurenard pilot	22.	0.048	13.	9.6	0.62	150.	2.00
		B	38	Chateaurenard industrial	36.	0.048	14.	3.5	0.58	81.	34.
	7		20	Delaware-Childers	2.7	1.04	5.4	8.5	0.33	40.	0.
11			24-25	El Dorado Chesney	1.6	8.7	2.6	9.4	1.6	73.	3.4
12			24-25	El Dorado Hegberg	1.3	8.7	7.0	5.4	0.21	82.	6.3
		C	32-34	Glennpool	7.5	8.1	5.0	9.9	0.20	36.	29.
13	8			Jones City	21.	8.5	9.0	4.0	([3])	68.	8.4
14	9		35	Loudon I	2.0	10.5	2.3	40.	0.	36.	15.
15			36	Loudon II	4.3	10.5	2.3	40.	([3])	184.	60.
16				Manvel	56.	10.7	2.5	25.	([3])	50.	12.
17	10		22, 23	North Burbank	16.	8.7	3.7	5.1	0.83	47.	19.
	11			Robinson: Henry W	5.0	1.6	10.	9.	([3])	191.	63.
	16			Robinson: 119R	2.	1.6	11.	7.	([3])	100.	38.
	17		15	Robinson: 219R	2.6	1.6	11.	10.	0.15	105.	32.
18			16-19	Robinson: M-1	20.([4])	1.6	10.	10.	0.14	105.	31.
19	18		6-8	Salem I	10.	12.	1.6	28.	0.	30.	17.
		D	10-11	Salem II	8.5	12.	3.6	18.	0.39	80.	47.
23	19			Sloss	23.	0.25	4.1	16.	0.36	100.	22.
25	20		9	West Burkburnett	19.	15.	1.6	15.	0.	30.	13.
26			30-31	Wilmington	5.2	3.0	8.0	6.4	([5])	66.	25.

[1]LFD is the numbering system of reference 51; LP is that of reference 49.

[2]WFRO = Waterflood residual oil.

[3]Not available.

[4]23 for 2.5-acre spacing, 18 for 5-acre spacing.

[5]Sulfonate co-surfactant used.

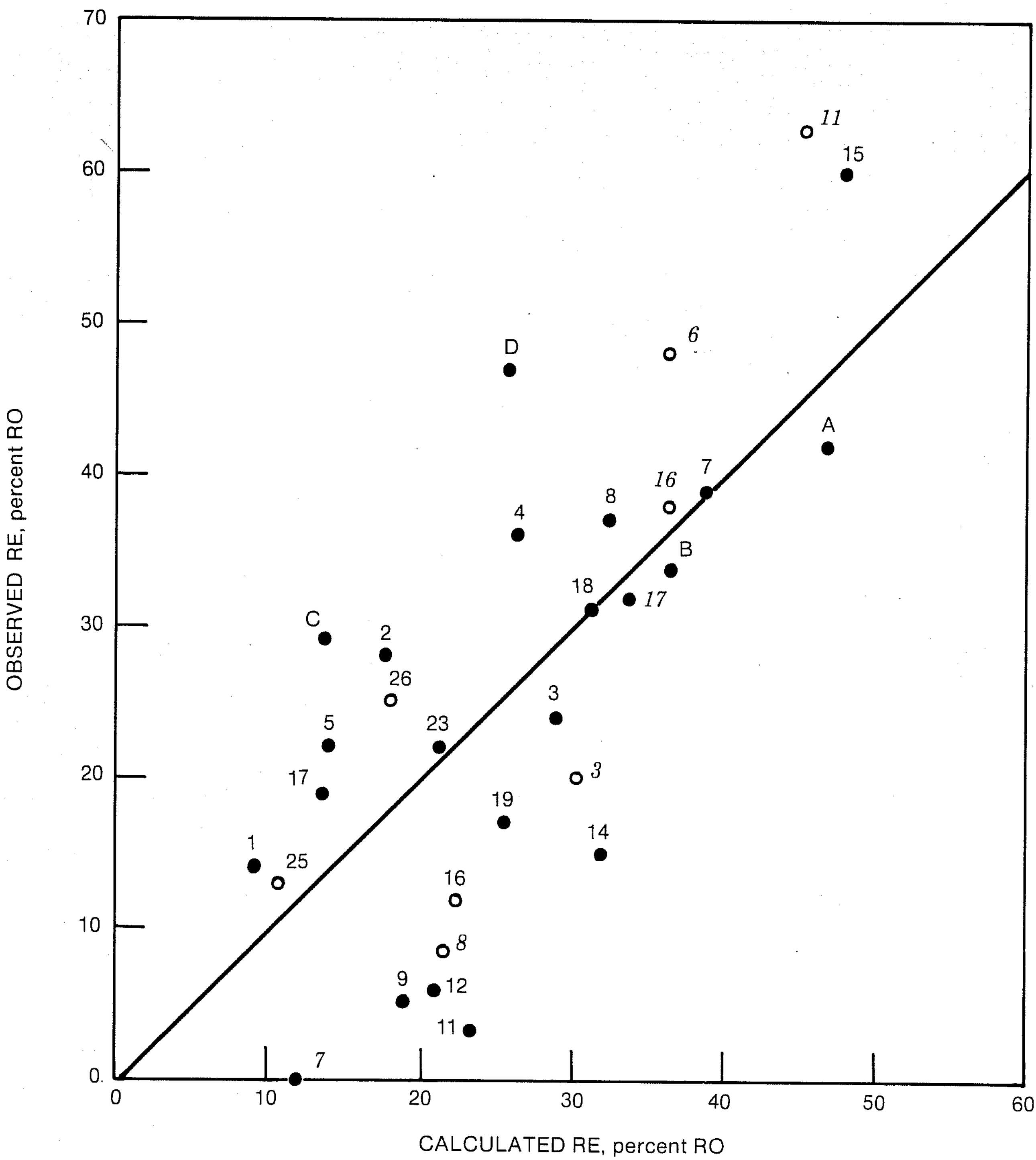

FIGURE 1. - Field test results: reported recovery efficiencies (RE, in percent of waterflood residual oil) vs. values calculated from equation 1. Numerals in Roman type are the numbers of Lowry, Ferrell, and Daubin;[51] italic numerals are numbers of Lake and Pope.[49] Letters are from table 1. Open symbols: incomplete data.